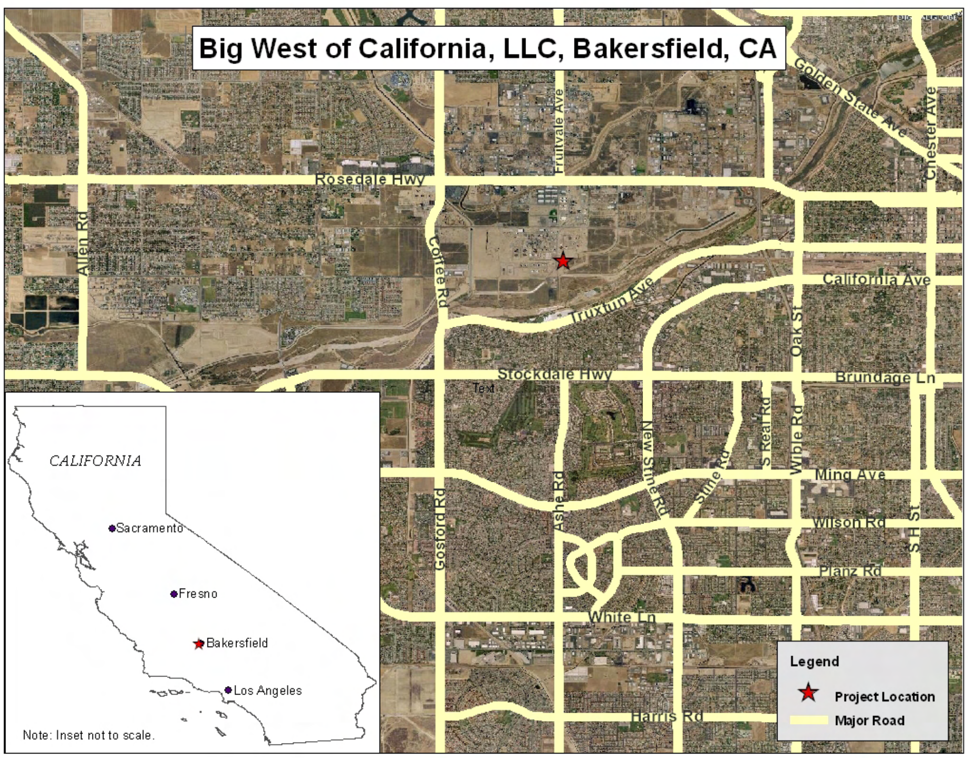
US ENVIRONMENTAL PROTECTION AGENCY
REGION IX

Statement of Basis and Ambient Air Quality Impact Report

For a Clean Air Act
Prevention of Significant Deterioration Permit

November 2, 2007



Big West of California, LLC
Bakersfield Refinery - Clean Fuels Project

PSD Permit # SJ-05-01 (06-029-S0033-1.0)

BIG WEST OF CALIFORNIA, LLC
BAKERSFIELD REFINERY – CLEAN FUELS PROJECT

Statement of Basis and
Ambient Air Quality Impact Report

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Acronyms and Abbreviations

AQRV	Air Quality Related Value
ARB	California Air Resources Board
ATS	Ammonium Thiosulfate Solution
BA	Biological Assessment
BACT	Best Achievable Control Technology
BO	Biological Opinion
BPD	Barrels per Day
BPIP	Building Profile Input Program
BTU	British Thermal Unit
CAA	Clean Air Act
CFP	Clean Fuels Project
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO2	Carbon Dioxide
DAT	Deposition Analysis Thresholds
EPA	Environmental Protection Agency
ESA	Endangered Species Act
E/U	Emission Unit
^{0}F	Degrees Fahrenheit
FCCU	Fluid Catalytic Cracking Unit
FLAG	Federal Land Managers' Air Quality Related Values Workgroup
FLM	Federal Land Manager
FWS	(US) Fish and Wildlife Service
g/bhp-hr	grams per brake horsepower hour
GEP	Good Engineering Practice
H2S	Hydrogen Sulfide
HGU2	Hydrogen Unit
hr	Hour
ISCST3	Industrial Source Complex Short-Term Model
Kg/ha/hr	kilogram per hectacre per hour
LAER	Lowest Achievable Emission Rate
lb	Pound
LPG	Liquified Petroleum Gas
MMBTU	Million British Thermal Units
MMSCFD	50 million standard cubic feet per day
MSA	Metropolitan Statistical Area
N	Elemental Nitrogen
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
NO_2	Nitrogen Dioxide
NOx	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen

PM2.5	Particulate Matter 2.5 microns in diameter or less
PM10	Particulate Matter 10 microns in diameter or less
ppm	Parts per Million
ppmvd	Parts per Million by Volume, Dry Basis
ppmv	Parts per Million by Volume
PSD	Prevention of Significant Deterioration
RBLC	RACT/BACT/LAER Clearinghouse
S	Elemental Sulfur
SCR	Selective Catalytic Reduction
SJVAPCD	San Joaquin Valley Air Pollution Control District
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SO_x	Sulfur Oxides
SWAATS	Sour Water Ammonia to Ammonium Thiosulfate Unit
tpy	tons per year
ug/m3	micrograms per cubic meter
USEPA US	Environmental Protection Agency
USFWS	US Fish and Wildlife Service
USNPS	US National Park Service
VGO-HDS	Vacuum Gas Oil Hydro-De-Sulfurization Unit
VOC	Volatile Organic Compounds
WA	Wilderness Area
WBAN	Weather Bureau Army Navy

BIG WEST OF CALIFORNIA, LLC
BAKERSFIELD REFINERY – CLEAN FUELS PROJECT

Statement of Basis and
Ambient Air Quality Impact Report

Executive Summary

Big West of California, LLC has requested approval to construct a Clean Fuels Project at its Bakersfield refinery. The Clean Fuels Project (CFP) will allow the conversion of intermediate products into gasoline and diesel fuel that meets California Air Resources Board (ARB) gasoline and diesel fuel specifications. These intermediates are currently being exported to other refineries for final processing. We believe that the proposed Clean Air Act Prevention of Significant Deterioration (PSD) permit is consistent with the requirements of our PSD permitting program for the following reasons:

- The proposed permit requires Best Available Control Technology (BACT) for Nitrogen Dioxide (NO_2 - referred to throughout this document as Nitrogen Oxides, or NO_x), Carbon Monoxide (CO), and Sulfur Dioxide (SO_2);

- We have determined that the proposed emission limits will protect Clean Air Act air quality standards for NO_x, CO, and SO_2;

- We have assessed other potential impacts, such as impacts on soils and vegetation, and assessed potential impacts on air quality, visibility, and deposition in Class I areas given special protection under the Clean Air Act;

- We are consulting with the Fish and Wildlife Service under Section 7 of the Endangered Species Act to ensure that the proposed project does not jeopardize any endangered or threatened species (including the San Joaquin kit fox), or result in the destruction or adverse modification of such species' designated critical habitat.

BIG WEST OF CALIFORNIA, LLC
BAKERSFIELD REFINERY – CLEAN FUELS PROJECT

Statement of Basis and
Ambient Air Quality Impact Report

1. Purpose of This Document

This document serves as the Statement of Basis and Ambient Air Quality Impact Report for a proposed Prevention of Significant Deterioration (PSD) permit for the Clean Fuels Project at the Big West of California, LLC Bakersfield Refinery. This document describes the legal and factual rationale for the proposed permit, including requirements under the PSD regulations at 40 CFR §52.21.
This document also serves as the fact sheet to meet the requirements of Part 40 of the Code of Federal Regulations (CFR) sections 124.7 and 124.8.

2. Applicant

Big West of California, LLC
A wholly-owned subsidiary of Flying J, Inc.

Mailing address:
P.O. Box 1132
Bakersfield, CA 93302

3. Project Location

Big West of California, LLC (Big West) recently purchased the Bakersfield refinery from Shell Oil Company. The Bakersfield refinery is located at 6451 Rosedale Highway about 2.5 miles northwest of the City of Bakersfield (zoned M-3—heavy industry), in the southernmost portion of the San Joaquin Valley Air Basin.

The Bakersfield refinery is divided into three areas: Areas 1 and 2 (which are contiguous), and Area 3 (which is located at 3663 Gibson Street). Areas 1 and 2 are bound by Mohawk Street to the east, Rosedale Highway to the north, Wedding Lane to the west, and Kern River to the south. Only Areas 1 and 2 will be modified as part of the Clean Fuels Project.

The map on the following page shows the approximate location for the Clean Fuels Project.

4. Project Description

Big West is proposing to construct and operate additional processing units within the existing refinery to increase production of gasoline and diesel fuel that meets California Air Resources Board (ARB) gasoline and diesel fuel specifications. The addition of these units and associated modifications is referred to as the Clean Fuels Project (CFP). Once the CFP is complete, the amount of intermediate petroleum products being exported will be significantly reduced as compared to historical operations; total crude throughput will remain at 70,000 barrels per day (BPD).

Existing refinery process units include crude distillation, delayed coking, hydrocracking, and catalytic reforming. In addition, the refinery includes a number of ancillary and support facilities including steam boilers, process heaters, cooling towers, storage tanks, and interconnecting pipelines. There is also a terminal with both truck and rail loading facilities. The Bakersfield refinery currently produces the following products and intermediates:

- Gas oils (25,000 BPD);
- Gasoline (21,800 BPD);

- Diesel fuel (20,300 BPD);
- Fuel gas; and
- Petroleum coke.

The CFP will add the following new process units, with the following capacities:

- Vacuum Gas Oil Hydro-De-Sulfurization Unit (VGO-HDS): 30,000 BPD;
- Fluid Catalytic Cracking Unit (FCCU): 30,000 BPD;
- Liquefied Petroleum Gas (LPG) Merox Treating Unit (Merox unit): 13,500 BPD;
- Alkylation Unit (Alky unit): 13,500 BPD;
- Hydrogen Unit (HGU2): 50 million standard cubic feet per day (MMSCFD);
- Sour Water Ammonia to Ammonium ThioSulfate (SWAATS) unit: 1,200 BPD.

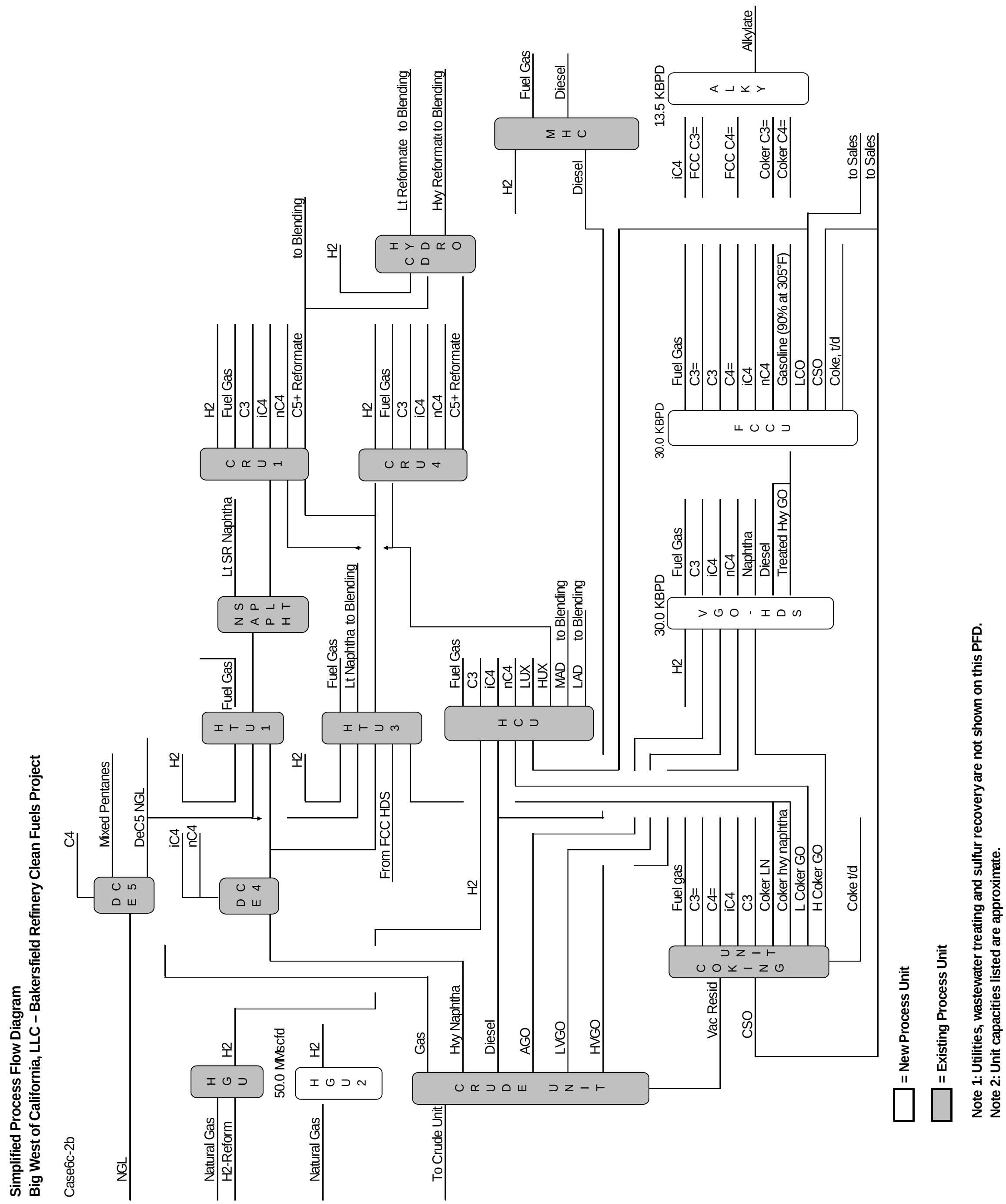
Other new emission units include the following:

- A new sour water stripper to handle the additional sour water coming from the new VGO-HDS and FCCU
- Four new process heaters (two VGO-HDS heaters, one HGU2 heater, and one Alky unit heater)
- One new ground flare, equipped with a flare gas recovery system
- Two or three new emergency firewater pumps driven by diesel engines

Other changes that will be made as part of this project but which will not result in increased emissions of NO_x, SO_x, or CO include:

- Two new cooling towers (one dedicated to the Alky unit, and another for the remaining cooling water needs)
- Some new loading facilities at the Refinery and the adjacent Sales Terminal will be modified to streamline increased gasoline and diesel production.
- Three existing storage tanks will be modified.
- A new amine treatment unit will be constructed.
- A new wastewater treatment facility.
- The only existing process unit within the Bakersfield refinery that will be modified as part of the CFP is the Mild Hydrocracker. The Mild Hydrocracker unit itself will be modified to allow for additional catalyst in the process unit and allow for processing of distillate from the crude unit. However, no modification will be made to the associated heaters.
- A new 250,000 barrel floating roof crude storage tank will be constructed.

The diagram below is a simplified process flow diagram.



The air pollution control equipment and techniques at the plant will consist of the following:

- A combination of a low NO_x regenerator design and selective catalytic reduction (SCR) for the FCCU to control NO_x emissions to 20 parts per million by volume, dry basis (ppmvd), corrected to 0 percent oxygen (% O2), on a 365-day rolling average, and to 40 ppmvd, corrected to 0% O2, on a 7-day rolling average.
- SO_2-reducing catalyst additives in the FCCU to limit SO_2 emissions to 20 ppmvd, corrected to 0% O2, on a 365-day rolling average, and to 50 ppmvd, corrected to 0% O2, on a 7-day rolling average.
- An FCCU regenerator design that employs full burn combustion technology, designed to ensure nearly complete oxidation of CO to CO_2 in the regenerator exhaust, to limit CO emissions to 50 ppmvd, corrected to 0% O2, on a rolling 365-day average.
- Oxidation catalyst added to the FCCU to control CO emissions during each startup event.
- A combination of low-NO_x burners and SCR on the Alky unit heater and the HGU2 heater to control NO_x emissions to 5 ppmvd, corrected to 3% oxygen, on a 15-minute average.
- Low NO_x burners on the two VGO-HDS heaters subject to BACT to control NO_x emissions to 20 ppmvd, corrected to 3% oxygen, on a 3-hour rolling average.
- The SWAATS unit will be a new process unit designed for sulfur recovery, with a vendor guarantee of 30 ppmvd SO_2 emissions, corrected to 0% oxygen, on a 3-hour average.
- A multipoint ground flare equipped with a flare gas recovery system.
- The use of a safer, modified hydrogen fluoride alkylation process (UOP's "Alkad").
- The Applicant will treat the refinery fuel gas to achieve a limit of 40 ppmv total reduced sulfur, as H_2S (4-hour rolling average) and 25 ppm H_2S (on an annual average).

5. Emissions from the Project

Pollutant emission rates from the proposed project have been estimated from project design criteria, proposed BACT limits, and emission factors. The first table below displays the estimated net emission increases of Criteria PSD pollutants from the Clean Fuels Project, which will be regulated by this PSD permit. The second table below displays the estimated net emission increases of non-attainment New Source Review (NSR) pollutants from the Clean Fuels Project, which will be regulated by a non-attainment NSR permit to be issued by the San Joaquin Valley Air Pollution Control District. For further discussion of PSD and NSR permitting, see Section 6 below.

PSD Pollutant (Criteria)	**Emissions (tpy)**
Carbon Monoxide (CO)	166.44
Nitrogen Oxides (NO_x)	83.2
Sulfur Dioxide (SO_2)	84.9

NSR Pollutant	**Emissions (tpy)**
Particulate Matter (PM_{10})	76.5
Volatile Organic Compounds (VOC)	102.5

6. Applicability of Prevention of Significant Deterioration Regulations

San Joaquin Valley is classified as an attainment area for NO2, SO_2, and CO. The proposed project exceeds the significance thresholds for these pollutants of 40 tpy, 40 tpy, and 100 tpy, respectively; therefore, the Clean Fuels Project is subject to Prevention of Significant Deterioration (PSD) permitting for these three pollutants and is considered a major modification. Lead will not be emitted in amounts above the significance threshold therefore PSD will not apply to this criteria pollutant. The PSD regulations also apply to emissions of non-criteria pollutants (sulfuric acid mist, reduced sulfur compounds, and municipal waste combustor pollutants) emitted in amounts above established significance thresholds. Emissions of these non-criteria PSD pollutants from the CFP will be far below the significance thresholds. Therefore, PSD is not triggered for these pollutants. San Joaquin Valley is classified as a non-attainment area for ozone; therefore, the Clean Fuels Project is subject to non-attainment New Source Review (NSR) for VOC (an ozone precursor). The San Joaquin Valley is also designated as non-attainment for fine particulate matter with aerodynamic diameter less than 2.5 micrometers ($PM_{2.5}$) and is subject to non-attainment NSR for $PM_{2.5}$. On October 17, 2006, EPA determined that San Joaquin Valley had attained the NAAQS for PM_{10} based on monitoring data from 2003-2005. However, until the State submits, and EPA approves, a PM_{10} maintenance plan and a request for redesignation to attainment, the San Joaquin Valley will be classified as a serious PM_{10} non-attainment area. Therefore, the Clean Fuels Project is also subject to non-attainment NSR for PM_{10}. San Joaquin Valley Air Pollution Control District (SJVAPCD or the District) is the local permitting authority responsible for non-attainment NSR permitting. SJVAPCD will also be proposing a Clean Air Act Title V Operating Permit coincidentally with the NSR permit. The combined permit will be called a Certificate of Conformity.

7. Best Available Control Technology

Section 169(3) of the Clean Air Act (CAA) defines BACT as follows:

> The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act emitted from or which results from any major emitting facility. The permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, makes a BACT determination through application of processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of BACT result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 (NSPS) or 7412 (NESHAP) of the Clean Air Act, or any State Implementation Plan.

For attainment pollutants being regulated in a PSD permit, EPA evaluates emissions control requirements through a “top-down” BACT determination, which is described in EPA’s New Source Review Workshop Manual, Draft October 1990 (“PSD Manual”). In brief, the top-down process requires that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent technology. That technology is established as BACT unless it is demonstrated that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not achievable for the case at hand. If the most stringent technology is eliminated, then the next most stringent option is evaluated until BACT is determined. The top-down BACT analysis is a case-by-case exercise for the particular source under evaluation. In summary, the five steps involved in a top-down BACT evaluation are:

1. Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

2. Eliminate technically infeasible technology options;

3. Rank remaining control technologies by control effectiveness;

4. Evaluate the most effective control alternative and document results; if top option is not selected as BACT, evaluate next most effective control option; and

5. Select BACT, which will be the most stringent technology not rejected based on technical, energy, environmental, and economic considerations.

BACT is required for NO_x, CO, and SO_2 for the following emission units: the FCCU, the SWAATS units, refinery process heaters, the FCCU startup air heater, the flare, and the emergency diesel firewater pump engines because these units have the potential to emit air pollutants for which PSD has been triggered. Unless otherwise noted below, in making a final proposed determination of BACT for the above pollutants and emission units, we consulted Big West's application materials, as well as EPA's RACT/BACT/LAER Clearinghouse (RBLC); California Air Resources Board Statewide BACT Clearinghouse; EPA's existing and proposed New Source Performance Standards for Petroleum Refineries, NSPS Subparts J and Ja; and EPA's Global Refinery Consent Decrees.

7.1. FCCU

Following removal of contaminants at the proposed new Hydro-De-Sulfurization unit, treated diesel and heavy gas oils from the existing delayed coker unit and crude unit will be sent to the proposed new Fluid Catalytic Cracking Unit (FCCU). The FCCU will convert these intermediate gas oils into lighter products, such as LPG (liquefied petroleum gas), gasoline, and diesel.

The FCCU will consist of three sections: the reactor/regenerator, the main fractionation section, and the gas concentration section. In the reactor/regenerator section, the intermediate gas oils will be "cracked" into smaller components in the presence of catalyst, and the "spent" catalyst will be stripped of coke-deposits formed during the cracking process and regenerated. After the reactor, the product stream will be sent to the main fractionation section, where the stream will be separated. “Overhead wet gas” and unstabilized gas streams will be sent to the gas concentration section, while light cycle oil will be reprocessed within the refinery.

Emissions are discussed below, along with the Best Available Control Technology determination for each PSD pollutant.

7.1.1. NO_x

NO_x is present in the FCCU regenerator flue gas. The NO_x is formed from the reaction of nitrogen with oxygen when the spent catalyst is regenerated. After steam-stripping hydrocarbons, the catalyst is sent to the regenerator where hot air is blown through the catalyst, burning off coke carbon and sulfur deposits.

The applicant has identified the following as possible technologies for the control of NO_x from the FCCU; all have been identified as being technologically feasible.

- Inherently low NO_x regenerator design
- Selective Catalytic Reduction (SCR)
- Low Temperature Oxidation (LoTOx)
- Selective Non-Catalytic Reduction (SNCR)
- NO_x reducing catalyst additives and low NO_x combustion promoters

The Applicant has proposed as BACT for NO_x an emission limit of 20 ppmvd (365-day rolling average), corrected to 0% oxygen, except during startups and shutdowns. The Applicant has proposed to achieve these limits through an inherently low- NO_x regenerator design (full-burn unit), coupled with SCR controls. The Applicant has stated that it cannot achieve the 20 ppmvd NO_x limit during periods of startup and shutdown because the equipment cannot be maintained at optimal operating conditions during these periods. Most importantly, temperature within the SCR catalyst cannot be maintained to achieve NO_x reduction efficiencies during startup. BACT for startup and shutdown periods is discussed in section 7.1.4.

The table below compares the BACT limit proposed by Big West with examples of the most recent and stringent NO_x permit limits for FCCUs. As shown below, the ExxonMobil Torrance Refinery permit includes an additional emission limit with a shorter averaging period of 40 ppm over a 7 day averaging period.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	20 ppm (365 day)	SCR + inherently low-NO_x regenerator design	Application	Estimated emissions: 16.8 lb/hr 36.9 tpy
ExxonMobil (Torrance Refinery)	2007	20 ppm (365 day) 40 ppm (7 day)	SCR	RBLC	
Valero (New Orleans)	2007	144.89 lb/hr 191.78 tpy 20 ppm (365 day)	No controls specified	RBLC	

Therefore, based on other similar, recently permitted operations EPA concludes that the emission level proposed by Big West, in conjunction with an additional emission limit of 40 ppmvd (7-day rolling average), corrected to 0% oxygen, for periods other than startup and shutdown, is the most stringent level of control and therefore represents BACT for the FCCU; no other analysis is needed since the most stringent control option was chosen.

7.1.2. CO

CO is also present in the FCCU regenerator flue gas. As noted above, “spent” catalyst is sent to the regenerator where hot air is blown through the catalyst to burn off coke carbon and sulfur deposits. FCCU regenerators can operate in one of two modes: full burn or partial burn. A partial burn unit will convert the coke deposits to CO and CO_2. A full burn unit, when properly designed and operated, will convert nearly all of the coke to CO_2, thereby limiting CO emissions. The Big West CFP FCCU will operate in full burn mode.

The applicant has identified the following as possible technologies for the control of CO from the FCCU.

- Good combustion practices
- Catalytic Oxidation

Catalytic oxidation was eliminated as a control option due to technical infeasibility, due to insufficient temperatures for the oxidation reaction to take place, and possible catalyst fouling due to particulate matter present in the exhaust stream.

The Applicant has proposed good combustion practices as BACT for CO control for the proposed FCCU, resulting in limits of 78 ppmvd (rolling 30-day average), corrected to 0% oxygen, and 59 ppmvd (rolling 365-day average), corrected to 0% oxygen, except during periods of startup and shutdown. BACT for startup and shutdown periods is discussed in section 7.1.4. As noted above, full-burn combustion technology, if properly designed and operated, will ensure nearly complete oxidation of CO to CO_2 in the regenerator exhaust. A CO boiler or afterburner is not necessary as in the case of partial-burn units.

Subsequent to the Applicant's submittal of its latest application (dated December 2006), the Applicant also proposed another emission limit of 500 ppmv (1-hour average), corrected to 0% oxygen

The table below compares the BACT limit proposed by Big West with examples of the most recent and stringent CO permit limits for FCCUs.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	78 ppm (30-day) 59 ppm (365-day) 500 ppm (1-hr)	Full burn technology and good combustion practices	Application	Estimated emissions: 128 (lb/hr) 66 (tpy)
Valero Ardmore	2007	50 ppm (365-day)	High Temperature Regeneration (partial burn unit)	RBLC	
Sunoco	2006	100 ppm (365-day) 500 ppm (1-hr)	CO Boiler	RBLC	

As shown in the table above, a lower limit based on a 365-day averaging period has been proposed since Big West submitted a revised application in December 2006. Therefore, the most stringent limit known to EPA is 50 ppm (365-day) in combination with a 78 ppm (30-day) limit and a 500 ppm (1-hr) limit. These limits can be achieved with the chosen technology, except during periods of startup and shutdown. Therefore, EPA concludes that this combination of limits represents BACT for the FCCU.

7.1.3. SO_2

Like NO_x and CO, SO_2 is also present in the FCCU regenerator flue gas, from the burn-off of sulfur deposits on spent catalyst. The applicant has identified the following as possible options for the control of SO_2 from the FCCU.

- Control of sulfur in the FCCU feed
- SO_2-reducing FCCU catalyst additives
- Wet gas scrubber

The Applicant has proposed, as BACT for SO_2, emission limits of 20 ppmvd (365-day rolling average) and 50 ppmvd (7-day rolling average), each corrected to 0% oxygen, except during periods of startup and shutdown. The Applicant has proposed to achieve these levels through a combination of hydrotreating the FCCU feed to reduce sulfur levels and the use of SO_2-reducing catalyst additives. Hydrotreating is a process that involves reacting hydrogen with sulfur at a high pressure and high temperature to remove sulfur from the FCCU feed before it ever reaches the FCCU. The SO_2 emission limits will not apply during periods of startup and shutdown, as exhaust gas temperatures may not be sufficient to allow the SO_2-reducing catalyst to provide effective control. BACT for startup and shutdown periods is discussed in section 7.1.4.

The table below compares the BACT limit proposed by Big West with examples of the most recent and stringent SO_2 permit limits for FCCUs.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	20 ppm (365-day) 50 ppm (7-day)	Hydrotreating fuel and SO_2-reducing catalyst	Application	Estimated emissions: 29.3 lb/hr 51.33 tpy
Tesoro Mandan	2007	10 ppm (365-day) 18 ppm (7-day)	Wet gas scrubber	RBLC	
Marathon Ashland	2007	20 ppm (365-day) 50 ppm (7-day)	Wet gas scrubber	RBLC	
Chevron El Segundo	2007	25 ppm (365-day) 50 ppm (7-day)	Low sulfur feed	RBLC	
ConocoPhillips Billings	2007	25 ppm (365-day) 50 ppm (7-day)	SO2-reducing catalyst	RBLC	

EPA is only aware of one other FCCU permitted with more stringent emission limitations than those proposed by Big West, and that is the

FCCU at the Tesoro Mandan refinery in North Dakota. These limits are being imposed as a result of EPA's Global Refinery Consent Decree Initiative and are to be achieved using an existing wet scrubber. At the time of drafting this statement of basis, testing had not been completed to determine if the new permit limit is being achieved. A wet gas scrubber has been rejected by the applicant because the use of such a system is incompatible with the particulate filters that will be needed to achieve LAER (Lowest Achievable Emission Rate) for PM 2.5[1], and with the SCR system used to control NO_x. Therefore, the most stringent control option is not achievable in this case due to environmental considerations. The next best option for this project is the use of low sulfur feed and SO_2-reducing catalyst.

Therefore, EPA concludes that the emission level proposed by Big West, for periods other than startup and shutdown, is the most stringent level of control and therefore represents BACT for the FCCU.

7.1.4. Startup and Shutdown Conditions

The applicant anticipates needing to shutdown the FCCU periodically for maintenance, approximately once every 2-5 years. As noted in the analyses above, the stringent BACT limits proposed for normal periods of operation cannot be met during periods of startup and shutdown, due to decreased effectiveness of pollution controls during these periods. Therefore, EPA is proposing to set alternate BACT limits for periods of startup and shutdown.

For periods of startup and shutdowns, the Applicant has proposed, as BACT, work practice standards in the form of a startup/shutdown plan. For control of CO emissions, the Applicant has also proposed a CO-reducing catalyst to be loaded into the regenerator of the FCCU during the startup process. For control of SO_2 emissions, the Applicant has also proposed the following work practice standards:

- Use of refinery fuel gas meeting BACT requirements in the start-up heater;
- Use of hydrotreated feed as torch oil.

[1] The particulate filter will achieve a control efficiency of >99.9%.

The Applicant will submit a startup/shutdown plan which must be approved by both EPA and the District before initial startup of the heaters. The startup/shutdown plan will be maintained at the facility. To be considered as BACT, the startup/shutdown plant must include the following work practice standards, at minimum:

- Prior to operation of the FCCU startup air heater (as described in the bullet point below), the Main Air Blower (the air blower immediately upstream of the FCCU startup air heater) is the only device used to heat the regenerator.
- The FCCU startup air heater will be started and operated after the regenerator temperature reaches the lesser of (1) 300°F, or (2) 60°F below the Main Air Blower discharge temperature*.
- Ammonia will be injected into the SCR once exhaust temperatures reach the minimum operating temperature of the SCR as specified by the manufacturer. The minimum operating temperature of the SCR will be confirmed as part of the SCR design process and will be considered final once the startup/shutdown plan is submitted to both agencies for approval before initial startup of the heaters.
- Loading of equilibrium catalyst, including CO-reducing catalyst, into the regenerator will not be initiated before the regenerator temperature reaches 1000°F*.

Startup/Shutdown work practice standards will apply in lieu of the steady-state BACT limits as follows:

- The duration of the FCCU startup interval during which the source will not be subject to the steady-state NO_x BACT limit for the FCCU will be limited to 8 hours.
- The duration of the FCCU startup interval during which the source will not be subject to the steady-state CO and SO_2 BACT limits for the FCCU will be limited to 64 hours.
- The shutdown duration time will be limited to 4 hours.

Based on the application, the 8-hour period allows time for the startup heater to heat the regenerator from approximately 300°F to approximately 615°F, at which point ammonia injection into the SCR can begin.

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* The startup/shutdown plan may contain temperatures that vary by ±10% from the 300°F and the 1000°F values.

Compliance with NO_x BACT limits is expected once the SCR is fully operational. The 64-hour period is required to allow time for torch oil combustion to increase the regenerator temperature, plus time to achieve stable feed and combustion conditions.

The above process is sequential; startup time beginning from burner ignition of the FCCU startup air heater will be no more than 72 hours in duration. The permit includes a requirement that the Permittee record and report the reasons for any startup exceeding 72 hours in duration.

The proposed work practice standards for the startup and shutdown periods are based on startup instructions provided by the equipment manufacturer and design engineers. EPA concurs that a startup/shutdown plan, submitted and approved before initial startup of the heaters; the proposed duration limits during the startup process for the source to achieve NO_x, CO, and SO_2 steady-state BACT emission limits; and the proposed shutdown duration limits represent BACT during startup and shutdown periods. The startup/shutdown plans and duration limits will be applicable requirements of the PSD permit. Note that we are not aware of other refinery permits setting BACT limits for startups and shutdowns.

7.2. SWAATS Unit

The proposed new FCCU and VGO-HDS units will produce streams of sour water. Water and steam come into contact with sulfur-containing gas and oils in these units, and can absorb the sulfur. This sulfur-laden water and steam is called “sour water.” The sour water is stripped of sulfur before being drained into the wastewater system. This sour water stripper gas is rich in sulfur and ammonia.

Typically, refineries use this feed in a Claus sulfur recovery process, where H_2S is converted to liquid elemental sulfur, and shipped offsite and sold. The CFP will be using an alternate process, converting this feed (containing H_2S, SO_2, and ammonia) to a marketable liquid fertilizer product (ammonium thiosulfate solution, or “ATS”) using a Sour Water Ammonia to Ammonium ThioSulfate (SWAATS) process. The SWAATS unit will consist of two sour water stripper gas absorbers, an H_2S oxidation process, an SO_2 absorber, and a wet scrubber. Because the end product from an ATS plant differs from the end product of a Claus plant, the SWAATS unit is not considered in the same class and category of source as a Claus plant.

Emissions from the SWAATS unit are discussed below, along with the Best Available Control Technology determination for each PSD pollutant. It should be noted that the Applicant conducted a review of the EPA RBLC and local California databases and found no entries pertaining to ammonium thiosulfate production units, with one exception. The Applicant found one entry in the BACT database for the South Coast Air Quality Management District, but it addressed BACT only for PM_{10} emissions.

The Applicant also conducted its own survey of existing ammonium thiosulfate plants and found that none of these plants used the SWAATS process, which is a recently patented process from Thiosolv. The first commercial unit is currently under construction. The SWAATS process involves the use of sour water as a feed, which has the potential to introduce hydrocarbon into the process. In contrast, the surveyed ammonium thiosulfate plants use feed materials such as elemental sulfur and purchased aqueous ammonia.

Because BACT analyses for the SWAATS process are not available, we are comparing the proposed BACT limits to the limits for other ATS plants, identified during the applicant's survey of existing plants.

7.2.1. NO_x

The oxidation of H_2S occurs in two stages within the SWAATS process. The first stage is the reaction burner. The entire first stage of this process is conducted in a reducing environment. Because the formation of NO_x is an oxidative process, no NO_x is expected to form during this stage. The second stage is a catalytic oxidation process, which takes place at temperatures far too low for the formation of thermal NO_x. Based on these design aspects, NO_x emissions are not expected to be formed during, or emitted from, the SWAATS process. Therefore, a BACT analysis is not required.

7.2.2. CO

Hydrocarbon will be present in the sour water stripper gas that gets fed into the SWAATS unit. Some of the hydrocarbon will be stripped out in the SO_2 absorption section; the rest will be combusted in the SWAATS combustor/catalytic reactor during the H_2S oxidation process. Most of the hydrocarbon will be completely oxidized to CO_2, but some will be left as CO.

As noted above, the Applicant's review of the EPA RBLC database and local California BACT databases did not yield any information pertaining to CO emissions at ammonium thiosulfate plants. Of the 16 ATS facilities identified in the Applicant's survey, only one, Jupiter Sulphur, LLC at the ConocoPhillips Billings Montana refinery, specified limits for CO. None specified control technologies. However, through technology transfer and the examination of the source of CO in this CFP system, the Applicant proposed the following possible control technologies:

- Incineration of SO_2 scrubber exhaust
- Catalytic oxidation
- 3-phase separator for sour water
- Efficient combustion in the SWAATS unit

The Applicant ruled out incineration of SO_2 scrubber exhaust gas due to a number of factors including environmental impacts (causes an increase in NO_x emissions and other combustion products). The Applicant ruled out catalytic oxidation because the required temperature of 700° to 1000°F is higher than the temperatures of the SWAATS vent gas, which is expected to be only 130°F.

The Applicant has proposed as BACT for CO an emission limit of 100 ppmvd (3-hour average) by use of a 3-phase separator upstream of the SWAATS unit to treat the sour water stream, in combination with good combustion practices. The 3-phase separator will minimize CO emissions by reducing the amount of hydrocarbons, which would otherwise be converted to CO, introduced into the SWAATS unit. Good combustion practices will improve combustion efficiency, ensuring more complete oxidation of hydrocarbons to C02, with resultant decreases in CO.

As noted above, of the 16 ATS facilities identified during the Applicant's survey, only one, Jupiter Sulphur, LLC at the ConocoPhillips Billings Montana refinery, specified limits for CO. This limit is expressed as 1.76 tpy, and 0.4 lb/hr. The proposed BACT limit for the CFP of 100 ppm equates to a limit of 2.7 lb/hr and 11.76 tpy. According to the equipment manufacturer and the Applicant, however, the lower limits imposed on the Jupiter Sulphur ATS plant are not technically feasible for a refinery. ATS plants use a pure ammonia feed, while Big West will be using the ammonia present in the sour water stream as a feed, as a means to control sulfur. Because of the presence of hydrocarbon in the feed stream, CO emissions will be higher than if a pure ammonia stream were used.

Based on the above information, EPA concludes that the emission level proposed by Big West is the most stringent level of control achievable for a SWAATS plant and therefore represents BACT for the SWAATS unit.

7.2.3. SO_2

The SWAATS unit is inherently an SO_2 control technology in that it facilitates the reaction of H_2S to SO_2 under conditions designed to prevent formation of SO_3, then captures SO_2 as a reactant from the resulting gas stream. The only SO_x control technology the Applicant was able to identify in a review of existing ammonium thiosulfate production facilities was a scrubber. The proposed SWAATS unit includes a wet scrubber as part of its process.

The Applicant has proposed, as BACT for SO_2, an emission limit of 30 ppmv (3-hour average), corrected to 0% oxygen, from the SWAATS unit.

The SWAATS will be operated in lieu of a conventional Claus sulfur recovery system and tail gas treatment unit. The Applicant's review of the RBLC for conventional Claus and tail gas treatment units shows that the SWAATS system is the more effective control technology. The Applicant found, for conventional Claus and tail gas treatment units, a maximum required sulfur recovery efficiency of 99.8% and the lowest SO_2 limit of 60 ppmv SO_2 at 0% oxygen. The Applicant's proposed SWAATS system has a vendor-guaranteed sulfur recovery efficiency of 99.9% and SO_2 emission level of 30 ppmv at 0% oxygen.

The table below compares the BACT limit proposed by Big West with examples of the most recent and stringent SO_2 permit limits for Claus sulfur recovery plants, as well as to the limits identified for other ATS plants.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	30 ppm (3-hr) (=99.9% removal efficiency)	Wet scrubbing	Application	Estimated emissions: 1.8 lb/hr 8 tpy
Valero – St Charles	2007	115 lb/hr	Thermal oxidizer - Comply with NSPS J	RBLC	Sulfur Recovery Unit
Marathon – Garyville	2006	93.41 ppm	Thermal oxidizers	RBLC	Sulfur Recovery Unit
Sunoco – Toledo	2006	250 ppm (12-hr)	SRU with tail gas treatment units and incinerator	RBLC	Sulfur Recovery Unit
Poole Chemical	NA	1.84 lb/hr 8 tpy	Scrubber	Applicant Survey	ATS Plant
Jupiter Sulphur, LLC – Ponca City	NA	99.5% removal efficiency	Assumed scrubber	Applicant Survey	ATS Plant
Jupiter Sulphur, LLC - Billings	NA	167 ppm (12-hr) 25 lb/hr	Assumed scrubber	Applicant Survey	ATS Plant

Based on the above information, EPA concludes that the emission level proposed by Big West is the most stringent level of control and therefore represents BACT for the SWAATS unit.

7.3. Process Heaters

The following proposed new process heaters at the refinery are subject to BACT requirements for NO_x, SO_2, and CO emissions: an Alky unit isostripper reboiler – rated at 215 MMBtu/hr, an HGU2 furnace - rated at 641 MMBtu/hr, and two VGO-HDS process heaters - rated at 47 MMBtu/hr and 35 MMBtu/hr.

7.3.1. NO_x

NO_x is formed during the combustion of fossil fuels, including natural gas and refinery fuel gas, and is generally classified as either thermal NO_x or fuel NO_x. Thermal NO_x is formed when elemental nitrogen reacts with oxygen in the combustion air within the high temperature environment of the heater burners. Fuel NO_x is generated when nitrogen contained in the fuel itself is oxidized. NO_x emissions can be reduced using the following controls:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Combustion Controls (Low NO_x Burners)
- Flue Gas Recirculation
- Steam Injection
- Good Combustion Practice

The most effective level of control can be achieved using a combination of SCR and Low NO_x burners.

7.3.1.a. Large Heaters (>50 MMBtu/hr)

For the two larger heaters, the Applicant has proposed low- NO_x burners with selective catalytic reduction (SCR) technology. This combination of controls is capable of achieving a NO_x concentration of 5.0 ppmvd or less on a 15-minute average, corrected to 3% oxygen, except during periods of startup and shutdown. BACT for periods of startup and shutdown are discussed in section 7.3.4.

The table below compares the BACT limit proposed by Big West with examples of the most recent and stringent NO_x permit limits for large heaters fired on refinery fuel gas.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	5 ppm (15-min)	SCR + Low-NO_x burners	Application	Estimated emissions (based on 641 MMBtu heater): 0.006 lb/MMBtu 3.9 lb/hr 17 tpy
ConocoPhillips – Borger	2006	0.02 lb/MMBtu	SCR + Low-NO_x	RBLC	
Arizona Clean Fuels	2005	0.0125 lb/MMBtu	SCR + Low-NO_x burners	ADEQ Website	
Chevron El Segundo	2004	5 ppm (3-hr)	SCR + Low-NO_x burners	SCAQMD Website	

Based on the above information, EPA concludes that the emission level proposed by Big West is the most stringent level of control and therefore represents BACT for the larger process heaters during periods of normal operation.

7.3.1.b. Small Heaters (≤50 MMBtu/hr)

For the two smaller VGO-HDS heaters, the Applicant has proposed ultra-low- NO_x burners alone, which will achieve a NO_x exhaust concentration of 20.0 ppmvd or less (3-hour average), corrected to 3 percent oxygen, excluding startups and shutdowns. BACT for periods of startup and shutdown are discussed in section 7.3.4. The Applicant ruled out the use of post-combustion controls (i.e. SCR) based on economic impacts (in this case the use of SCR would cost >$39,000/ton of NO_x removed).

The table below compares the BACT limit proposed by Big West with examples of the most recent and stringent NO_x permit limits for small heaters fired on refinery fuel gas.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	20 ppm (3-hr)	Ultra-low-NO_x burners	Application	Estimated emissions: 35 MMBtu heater: 0.024 lb/MMBtu 50MMBtu heater: 0.03 lb/MMBtu
Valero – St Charles	2007	0.04 lb/MMBtu	Ultra-low-NO_x burners	RBLC	
Marathon – Garyville	2006	0.03 lb/MMBtu	Ultra-low-NO_x burners	RBLC	
Arizona Clean Fuels – Yuma	2005	0.025-0.035 lb/MMBtu	Low-NO_x burners	ADEQ Website	Range for different heaters 0.025-0.035 lb/MMBtu

Based on the above information, EPA concludes that the emission level proposed by Big West is the most stringent level of control required for other similar units and therefore represents BACT for the smaller process heaters during periods of normal operation.

CO

Carbon Monoxide is formed as a result of incomplete combustion. The following control techniques have been identified for the potential control of CO emissions:

- Good combustion technique
- Catalytic Oxidation

Control of CO can be accomplished by using good combustion practice, including providing adequate fuel residence time, excess oxygen and high temperature in the combustion zone to ensure complete combustion. It should be noted, however, that these control factors also tend to result in increased emissions of NO_x. Conversely, a low NO_x emission rate achieved through combustion modification techniques such as Low- NO_x burners can result in high levels of CO formation.

Control of CO could theoretically be achieved by the use of a catalytic oxidation system; however we are not aware of any situation in which catalytic oxidation has been used to control emissions from refinery process heaters. While catalytic oxidation has been used successfully to control CO emissions from natural gas-fired turbine combustion units, the temperature of the exhaust gas from a refinery process heater is significantly lower than the temperature of the exhaust gas from a gas turbine. The effective temperature range for CO oxidation is between 600 ^{0}F and about 1000 ^{0}F. The exhaust gas from the heaters will range from 370-640 ^{0}F, depending on the heater. Because the temperatures will be under or on the very low end of the effective range, we anticipate that catalytic oxidation would not appreciable affect the emissions from the heaters. We therefore consider the application of catalytic oxidation to these heaters to be technically infeasible. For the control of both the larger and the smaller heaters, the applicant has proposed to achieve BACT limits through good combustion practices and engineering design and the use of clean-burning fuel.

7.3.2.a. Large Heaters (>50 MMBtu/hr)

For the two larger heaters, the Applicant has proposed, as BACT for CO, an emission limit of 10 ppmvd (3-hour average), corrected to 3% oxygen, except during periods of startup and shutdown. BACT for periods of startup and shutdown are discussed below.

The table below compares the BACT limit proposed by Big West with examples of the most recent and stringent CO permit limits for large heaters fired on refinery fuel gas.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	10 ppm (3-hr)	Good combustion techniques + clean burning fuel	Application	Estimated emissions: (based on 641 MMBtu heater): 0.007 lb/MMBtu 4.7 lb/hr 20.76 tpy
Chevron Pascagoula	2007	50 ppm (12-month)	NA	RBLC	
ConocoPhillips – Borger	2006	100 ppm	Good combustion practices	RBLC	
Arizona Clean Fuels	2005	0.016 lb/MMBtu (3-hr)	Good combustion practices	ADEQ Website	
Chevron El Segundo	2004	10 ppm (3-hr)	Good combustion practices	SCAQMD Website	

Based on the above information, EPA concludes that the emission level proposed by Big West is the most stringent level of control and therefore represents BACT for the larger process heaters during periods of normal operation.

7.3.2.b. Small Heaters (≤50 MMBtu/hr)

For the two smaller VGO-HDS heaters, the Applicant has proposed, as BACT for CO, an emission limit of 50 ppmvd (3-hour average), corrected to 3% oxygen, except during periods of startup and shutdown. BACT for periods of startup and shutdown are discussed below.

The table below compares the BACT limit proposed by Big West with examples of the most recent and stringent CO permit limits for small heaters fired on refinery fuel gas.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	50 ppm (3-hr)	Good combustion techniques + clean burning fuel	Application	Estimated emissions (based on larger of 2 heaters): 0.037 lb/MMBtu
Valero – St Charles	2007	0.08 lb/MMBtu (1-hr)	Good combustion techniques	RBLC	
Marathon – Garyville	2006	0.03 lb/MMBtu	Good combustion techniques	RBLC	
Arizona Clean Fuels – Yuma	2005	0.04 lb/MMBtu (3-hr)	Good combustion techniques	ADEQ Website	

Based on the above information, EPA concludes that the emission level proposed by Big West is the most stringent level of control required for other similar units and therefore represents BACT for the smaller process heaters during periods of normal operation.

SO_2

SO_2 is formed from combustion of sulfur in the fuel gas. The amount of SO_2 produced is directly dependent on the amount of sulfur in the fuel. Fuel gas generated at the refinery can be treated to remove sulfur (in the form of hydrogen sulfide) before it is combusted. Refinery fuel gas amine treatment systems are capable of removing 98+% of the hydrogen sulfide.

Only one control method is in use to control SO_2 emissions from combustion units that are fired exclusively on refinery fuel gas: to limit the sulfur content of the fuel. A limit on the total reduced sulfur content is more stringent than a limit just on H_2S since the other sulfur species (e.g., carbon disulfide, mercaptan, etc.) remain uncontrolled and may comprise a significant source of sulfur in refinery fuel gas streams.

In its revised application of December, 2006, the Applicant proposed limiting the total reduced sulfur content of the refinery fuel gas to 100 ppmv (3-hour rolling average) as BACT for SO_2 control for the proposed heaters. This limit was, at the time, believed to be the lowest achievable fuel gas limit for the Clean Fuels Project, based on information from the developer of the amine treatment system to be used for the CFP. However, in a letter to EPA, dated June 28, 2007, the Applicant proposed the addition of a caustic scrubber to the amine treatment system to allow the CFP to achieve a lower level of sulfur in the fuel gas system. Based on this design improvement, the Applicant has proposed a BACT limit of 40 ppmv total sulfur (as H_2S, on a 4-hr average) for the refinery fuel gas.

The table below compares the BACT limit proposed by Big West with examples of the most recent and stringent limits for refinery fuel gas at other refineries.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	40 ppm (4-hr, total sulfur, as H_2S)	Sulfur treatment	Addendum to Application	
Valero – St Charles	2007	100 ppm (H_2S, annual)	Sulfur treatment	RBLC	
Marathon – Garyville	2006	25 ppm (annual, as H_2S)	Sulfur treatment	RBLC	
Arizona Clean Fuels – Yuma	2005	35 ppm (daily average)	Sulfur treatment	ADEQ Website	
Chevron El Segundo	2004	40 ppm (as H_2S)	NA	SCAQMD Website	

The permit for Arizona Clean Fuels was issued in 2004 for the construction of a brand new refinery in Yuma, AZ. The facility has not yet been constructed. The Applicant does not consider this fuel gas H_2S level to be achievable based on the expected pressures of the incoming streams. It should be noted, however, that the 40 ppm limit proposed by the Applicant has a shorter, more stringent, averaging period than the 35 ppm limit for Arizona Clean Fuels, which has a daily average.

The permit for the Marathon, Garyville refinery contains an annual limit on H_2S concentration in the fuel gas of 25 ppm. This limit is technically feasible for the CFP, and Big West has confirmed in an application update, dated September 24, 2007, that this limit can be achieved for the CFP.

Based on the above information, EPA concludes that the fuel gas sulfur limit proposed by Big West, combined with an additional annual limit of 25 ppm H_2S, is the most stringent level of control achievable and therefore represents BACT.

Startup and Shutdown Conditions

For periods of startup and shutdown, the Applicant has proposed, as BACT, work practice standards in the form of a startup/shutdown plan. The Applicant will submit a startup/shutdown plan which must be approved by both EPA and the District before initial startup of the heaters.

The startup/shutdown plan will be maintained at the facility.

To be considered as BACT, the startup/shutdown plan for the two larger heaters must include the following work practice standard, at minimum: ammonia will be injected into the SCR once exhaust temperatures reach the minimum operating temperature of the SCR as specified by the manufacturer, which is not to exceed 615°F. And the SCR must be in operation. This minimum operating temperature will be confirmed as part of the SCR design process and will be considered final once the startup/shutdown plan is submitted to both agencies for approval before initial startup of the heaters.

The applicant has proposed the following limits on startup and shutdown duration:

Heater	Startup Duration (hrs)	Shutdown Duration (hrs)
Alky unit heater (E/U 02)	4	4
HGU2 heater (E/U 03)	16	4
VGO-HDS heaters (E/Us 04 & 05)	4	4

EPA concurs that a startup/shutdown plan, submitted and approved before initial startup of the heaters, along with the proposed startup and shutdown duration limits, represent BACT during startup and shutdown periods. Note that we are not aware of other refinery permits setting BACT limits for startups and shutdowns.

7.4. FCCU Startup Air Heater

The FCCU startup air heater will only be operated during the startup process of the FCCU. The Applicant has proposed an operational limit of 120 hours per year on this unit. This heater vents through the FCCU regenerator stack, which is equipped with SCR. Because the heater vents through the FCCU, the emissions from the startup heater alone cannot be directly measured through a source test. Startup and shutdown duration limits will be established for the entire FCCU process as a whole. Note that we are not aware of other refinery permits setting BACT limits for startups and shutdowns. Air pollutants are formed in the same manner as for the process heaters – refer to section above for an explanation of pollutant formation.

7.4.1. NO_x

The Applicant has proposed a low- NO_x burner and work practice standards in the form of a startup/shutdown plan as BACT. The Applicant will submit a startup/shutdown plan for the entire FCCU process (see section 7.1.4. above) which must be approved by both EPA and the District before initial startup of the FCCU. EPA concurs that a startup/shutdown plan, submitted and approved before initial startup of the FCCU, along with the proposed startup and shutdown duration limits for the FCCU, represent BACT during startup and shutdown periods.

CO

The Applicant has proposed, as BACT for CO, an emission limit of 50 ppmvd (3-hour average), corrected to 3% oxygen, and work practice standards in the form of a startup/shutdown plan as BACT. The Applicant proposed to achieve the above limit through good combustion practices and engineering design and use of clean-burning fuel.

Since emissions from the FCCU startup air heater alone cannot be directly measured anyway, the proposed emission limit is not practicably enforceable. However, EPA concurs that good combustion practices, good engineering design, and use of clean-burning fuel to minimize emissions during startup and shutdown represent BACT during startup and shutdown periods. In addition, EPA concurs that a startup/shutdown plan, submitted and approved before initial startup of the FCCU, along with the proposed startup and shutdown duration limits for the FCCU, represent BACT during startup and shutdown periods.

7.4.3. SO_2

Refer to Section 7.3.3. above.

7.5 Multipoint Ground Flare

The CFP will include a ground level, multipoint flare to combust gases released from the new process units due to startups, shutdowns, and emergencies. The multipoint flare can be sized to handle variable flow rates and pressures, has low thermal radiation levels, and a concealed flame. Although the flare is being installed as a control device, it will also be a source of PSD pollutants; therefore a BACT determination is required. Minimizing emissions from flares depends primarily on two factors: reducing the frequency and amount of gas flared and promoting efficient combustion. BACT for refinery flares is generally expressed as design and work practice standards rather than emission limits/rates.

In making our BACT determinations for the CFP flare, we consulted EPA's RACT/BACT/LAER Clearinghouse; because the RBLC does not contain many control options for flares, in making our BACT determination we relied heavily on flare control and monitoring rules from the South Coast Air Quality Management District, the Bay Area Air Quality Management District, and the San Joaquin Valley Air Pollution Control District; EPA's existing and proposed New Source Performance Standards for Petroleum Refineries, NSPS Subparts J and Ja; and EPA Consent Decrees.

7.5.1 NO_x

NO_x is formed as a result of the combustion of refinery fuel gas in the flare (and natural gas from the flare pilot). NO_x emissions from the flare can be best reduced by promoting efficient combustion and by minimizing the amount of gas flared.

Control options to promote efficient combustion consist of designing the flare in accordance with 40 CFR Parts 60.18 and 63.11, and using a flare designed with air or steam assisted combustion and staged combustion. The Big West flare will be designed to achieve a NO_x emission rate of 0.068 lb/MMBtu, as required by San Joaquin Valley Air Pollution Control District's Rule 4311.

Options to minimize flaring include installing a flare gas recovery system with adequate compressor capacity to recover routine gas vents, implementing a flare minimization plan to reduce flaring resulting from startups, shutdowns, and malfunctions, and conducting cause analyses of flaring events.

We are proposing as BACT all of the above control options, with the following exception:

40 CFR Parts 60.18 and 63.11 have maximum velocity requirements for flares. However, these requirements are only applicable if the flare is used to combust routinely released gases. These maximum velocity requirements are not achievable for the flare selected by Big West, however, the permit prohibits Big West from using the flare to combust routine gases and it is therefore expected that Big West will meet the requirements of 40 CFR Parts 60.18 and 63.11.

The multipoint ground flare was selected by Big West because it allows for the emergency flaring of a wide range of flow rates at both high and low pressures. According to Big West, it would take multiple enclosed, ground level flares and a ground level or elevated high-pressure flare to achieve the same purpose. Additionally, at least one flare manufacturer indicated that enclosed flares are expected to have higher combustion temperatures, and therefore higher NO_x emissions than non-enclosed flares. For this particular operation we see the multipoint ground flare as being the environmentally superior choice.

The table below compares the BACT techniques proposed by Big West with examples of the most recent and stringent BACT determinations for refinery flares.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	NA	Flare minimization, good design, good engineering practice	Application	Estimated Emissions: 0.068 lb/MMBtu 25.75 lb/hr 0.97 tpy
Valero – St Charles	2007	25.9 lb/hr	Proper equipment design and operation, good combustion practices, and use of gaseous fuels	RBLC	
Marathon – Garyville	2006	NA	Comply with 60.18	RBLC	
Sunoco – Toledo	2006	19.34 lb/hr; 84.7 tpy	NA	RBLC	

The flare at the Sunoco, Toldeo refinery is subject to a lower pound per hour limit than the estimated maximum hourly emissions from the CFP flare, however, the ton per year limit is far higher than the estimated annual emissions from the Big West flare. Annual emissions from the Big West flare are expected to be much lower than the annual limits for the Sunoco flare. This is due to the use of a flare gas recovery system with redundant compressor capacity, and the stringent flare minimization requirements that are being imposed by this permit.

Based on the above information, EPA concludes that the control techniques identified for Big West's CFP flare are the most stringent control methods required for other similar units and that, therefore, these control methods represent BACT for the flare.

7.5.2. CO

CO is formed as a result of incomplete combustion of refinery fuel gas in the flare. CO emissions from the flare can be best reduced by promoting efficient combustion and by minimizing the amount of gas flared.

Control options to promote efficient combustion consist of designing the flare in accordance with 40 CFR Parts 60.18 and 63.11, and using a flare designed with air or steam assisted combustion and staged combustion. Smokeless operation of the flare (in other words, operating the flare with no visible emissions) is key to ensuring efficient combustion, and thereby limiting CO emissions. The PSD permit will limit visible emissions as an indicator of efficient combustion.

Options to minimize flaring include installing a flare gas recovery system with adequate compressor capacity to recover routine gas vents, implementing a flare minimization plan to reduce flaring resulting from startups, shutdowns, and malfunctions, and conducting cause analyses of flaring events.

We are proposing as BACT all of the above control options, with the following exception:

40 CFR Parts 60.18 and 63.11 have maximum velocity requirements for flares. However, these requirements are only applicable if the flare is used to combust routinely released gases. These maximum velocity

requirements are not achievable for the flare selected by Big West, however, the permit prohibits Big West from using the flare to combust routine gases and it is therefore expected that Big West will meet the requirements of 40 CFR Parts 60.18 and 63.11.

The multipoint ground flare was selected by Big West because it allows for the emergency flaring of a wide range of flow rates at both high and low pressures. According to Big West, it would take multiple enclosed, ground level flares and a ground level or elevated high-pressure flare to achieve the same purpose. Additionally, at least one flare manufacturer indicated that enclosed flares are expected to have higher combustion temperatures, and therefore higher NO_x emissions than non-enclosed flares. For this particular operation we see the multipoint ground flare as being the environmentally superior choice.

The table below compares the BACT techniques proposed by Big West with examples of the most recent and stringent BACT determinations for refinery flares.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	NA	Flare minimization, good design, good engineering practice, no visible emissions	Application	Estimated Emissions: 0.37 lb/MMBtu 140.11 lb/hr 5.28 tpy
Valero – St Charles	2007	56.1 lb/hr	Proper equipment design and operation, good combustion practices, and use of gaseous fuels	RBLC	
Marathon – Garyville	2006	NA	Comply with 60.18	RBLC	
Sunoco – Toledo	2006	16.25 lb/hr; 71.2 tpy	NA	RBLC	

As discussed for NO_x, above, while the Sunoco, Toledo and Valero, St Charles permits have pound per hour limits that are lower than the maximum expected emissions from the Big West flare, annual emissions from the Big West flare are expected to me much lower than the annual limits for the Sunoco and Valero flares. This is due to the use of a flare gas recovery system with redundant compressor capacity, and the stringent flare minimization requirements that are being imposed by this permit.

Based on the above information, EPA concludes that the control techniques identified above are the most stringent control methods required for other similar units and therefore these control methods represent BACT for the flare

7.5.3. SO_2

SO_2 is formed as a result of the combustion in the flare of fuel gas containing reduced sulfur compounds. SO_2 emissions from the flare can be best reduced by limiting the concentration of reduced sulfur compounds present in the refinery fuel gas, and by minimizing the amount of gas flared.

By treating sulfur in the fuel gas to 40 ppmv, Big West will minimize emissions of SO_2 during times when the flare is used. Big West will also be required to comply with the new NSPS Subpart Ja, which limits sulfur in the fuel gas to 60 ppmv on an hourly basis, and 160 ppmv on a 365-day basis. However, BigWest should not trigger these additional limits since the NSPS exempts flaring due to emergencies, process upsets, and startups and shutdowns; Big West is prohibited from using the flare under such circumstances. It is expected that all fuel gas combusted in the flare will be treated to a level of 40ppm sulfur, as H_2S.

Options to minimize flaring include installing a flare gas recovery system with adequate compressor capacity to recover routine gas vents, implementing a flare minimization plan to reduce flaring resulting from startups, shutdowns, and malfunctions, and conducting cause analyses of flaring events.

The table below compares the BACT techniques proposed by Big West with examples of the most recent and stringent BACT determinations for refinery flares.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	NA	Flare minimization, good design, good engineering practice, low sulfur fuel treated to 40 ppm sulfur	Application	Estimated Emissions: 99.91 lb/hr 0.20 tpy
Valero – St Charles	2007	50 lb/hr	Use of refinery fuel gas treated to 100ppm sulfur	RBLC	
Marathon – Garyville	2006	NA	Comply with 60.18	RBLC	
Sunoco – Toledo	2006	5.33 lb/hr; 23.35 tpy	NA	RBLC	

As noted above for NO_x and CO, annual emissions from the Big West flare are expected to be much lower than the emissions from the Valero and Sunoco flares. This is due to the use of a flare gas recovery system with redundant compressor capacity, and the stringent flare minimization requirements that are being imposed by this permit. Additionally, it should be noted that the fuel gas sulfur level will be lower, at 40 ppmv total sulfur (4-hr) and 25 ppm H_2S (annual), thereby reducing SO_2 emissions when gas is combusted.

Based on the above information, EPA concludes that the control techniques identified above are the most stringent control methods required for other similar units and therefore these control methods represent BACT for the flare.

7.6. Emergency Diesel Firewater Pump Engines

As part of the CFP, the Applicant will install new diesel-fired emergency internal combustion engines. Combustion of diesel fuel will result in emissions of NO_x and CO. SO_2 will be formed in small quantities. The Applicant is anticipating using two Cummins Model CFP15E-F10 engines, rated at 479 horsepower. These engines are expected to be UL-certified, Tier 3 engines. At a minimum, the engines will be Tier 2 engines and will meet the relevant California performance standards for NO_x, CO, and SO_2. Non-emergency use will be limited to the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 – "Standard for the Inspection, Testing, and Maintenance of water-based fire Protection Systems."

The table below compares the Tier 2 standards that we are proposing as BACT with examples of the most recent and stringent limits for emergency engines. All three PSD pollutants (NO_x, CO, and SO_2) are covered by this table.

Facility	Year	Limit	Control Technique	Source	Notes
Big West CFP	2006	Meet Tier 2 standards at a minimum: NO_x+ NMHC = 4.8 g/bhp-hr CO = 2.6 g/bhp-hr SO_2 = 15ppm sulfur diesel	Engine design	Application Addendum	Estimated emissions (conservative based on 3 engines, 525 HP each, tier 2 emission standards: NO_x = 15.42 lb/hr CO = 9.03 lb/hr SO_2 = 0.02 lb/hr
Creole Trail LNG	2007	NO_x = 37.95 lb/hr CO = 12.24 lb/hr SO_2 = NA	Engine design and good combustion practice	RBLC	
Archer Daniels Midland – Cedar Rapids	2007	Meet Tier 2 standards	Engine design	RBLC	

Therefore, based on other similar, recently permitted operations EPA concludes that the use of Tier 2 or Tier 3 engines, in conjunction with limiting use to emergencies and testing, is the most stringent level of control and represents BACT for these emergency fire pumps.

8. Air Quality Impacts

The PSD regulations require an ambient air quality impact analysis to determine the impacts of the proposed project on ambient air quality. For all regulated pollutants emitted in significant quantities, the analysis must consider whether the proposed project will cause a violation of (1) the applicable PSD increments, and (2) the National Ambient Air Quality Standards (NAAQS).

A discussion on the general approach, existing air quality, air quality model selection, significant impact levels, de minimus monitoring levels, PSD increment consumption, and compliance with ambient air quality standards is presented below.

8.1. Ambient Data Requirements and Significant Impact Levels

PSD regulations contain provisions that require an applicant to provide an ambient air quality analysis, which may include pre-application monitoring data, and in some instances post-construction monitoring data, for any pollutant proposed to be emitted in significant amounts by a new major source or major modification. If predicted ambient impacts or existing ambient pollutant concentrations are less than the significant monitoring thresholds prescribed in the PSD regulations, then an applicant may be exempted from this requirement.

Maximum annual and short-term emissions from the CFP were modeled and the resulting impacts compared with the federal pre-construction monitoring significance levels. The results of the significant impact analysis are shown in Table 8.2-1. Monitoring significance levels would be not exceeded for any pollutant, therefore pre-construction ambient air quality monitoring has not been proposed for this project.

8.2 Dispersion Modeling Analysis

The air quality impacts in the Class II area surrounding the Big West refinery were determined with the most recent version of the EPA Industrial Source Complex Short-Term Model (ISCST3, version dated 02035; USEPA, 1995a). The ability of the ISCST3 model to accommodate varying source types and terrain makes it an appropriate selection for this analysis. The November 9, 2005, *Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose Dispersion model and Other Revisions*; *Final Rule* indicated that "beginning one year after promulgation of today's notice, (1) applications of ISC3 with approved protocols may be accepted." The dispersion modeling protocol for this application was submitted to the EPA and Federal Land Managers (FLM) in May 2005, and the permit application for Big West was determined to be complete in April, 2006. Therefore, the use of ISC3 is acceptable for this application. The area was classified as urban, based on the Auer methodology.

EPA recognizes that nearby buildings can cause plume downwash, leading to high pollutant concentrations. The applicant used the EPA Building Profile Input Program (BPIP) adapted for use with ISCST3 to determine the direction-dependent building input parameters (version 04274) (USEPA, 1995c; USEPA, 2004). Several of the nearby structures were sufficient to cause downwash of the stack exhaust; therefore the direction specific building downwash algorithms in ISC3 were used. This program was also used to calculate the Good Engineering Practice (GEP) stack height for each source location. No project stack height exceeded the calculated GEP stack height.

Five years of surface meteorological data from the Bakersfield meadow Field Airport National Weather Service site (WBAN 23155) were used, 1999, 2000, 2002, 2003, and 2004. The year 2001 did not have adequate wind speed capture, and therefore was not used. Upper air data collected at the Oakland station (WBAN 23230) for corresponding years was used.

Maximum annual and short-term emissions from the CFP were modeled and the resulting impacts compared with the Class II significance impact levels. The results of the significant impact analysis are shown in Table 8.2-1 and indicate that the Class II significant impact levels would not be exceeded for any pollutant. Because no pollutants exceeded the significant impact levels, as shown in Table 8.2-1, the proposed project does not trigger a NAAQS analysis or an increment consumption analysis under the PSD program regulations.

Table 8.2-1: Maximum Project Impacts Compared with Class II Significant Impact Levels and Monitoring Significance Levels

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	Class II Significant Impact Level ($\mu g/m^3$)	Monitoring Significance Level ($\mu g/m^3$)
NO_2	Annual	0.68	1.0	14
SO_2	Annual	0.83	1.0	NA
	3-hour	10.71	25.0	NA
	24-hour	3.37	5.0	13
CO	1-hour	183.42	2,000	NA
	8-hour	31.38	500	575

Notes:
[a] EPA default Ambient Ratio Method factor of 0.75 applied.
NA = Not applicable/not defined

8.3 Class I AQRV Impact Analysis

The Applicant has conducted a PSD impact analysis relative to Air Quality Related Values (AQRV) impacts on Class I areas located within 100 kilometers of the project location. Class I areas are national or regional areas of special natural, scenic, recreational, or historic value for which the PSD regulations provide special protection. Air quality degradation in all Class I areas is limited by Class I increments for SO_2, PM_{10}, and NO_2. No specific increment exists for the impact of CO on a Class I area. The nearest Class I area is the Dome Land Wilderness Area (WA), located approximately 80 km to the northeast of the refinery. San Rafael WA is the next closest Class I area, located approximately 90 km southwest of the refinery. Sequoia National Park is located just over 100 km away, to the north of the refinery.

For these areas, proposed project sources were modeled, and impacts compared to the PSD Class I modeling significance levels as defined by the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) (see Tables 8.3-1, 8.3-2, and 8.3-3). For each Class I area, modeling was also conducted to assess the effect of the proposed project on visibility and acid deposition.

To estimate air quality impacts at the Class I areas, the applicant used the CALPUFF model, which was run in a screening mode (Tier 2 or CALPUFF-lite). The CALPUFF model is a puff-type model that can incorporate three-dimensionally varying wind fields, wet and dry deposition, and atmospheric gas and particle phase chemistry. The FLM may request a CALPUFF modeling study at its discretion; however the FLM has determined CALPUFF-lite to be adequate at this time. The modeled concentration do not exceed the applicable FLAG threshold values for maximum concentrations of NO2, PM10, and SO2 in the Class I areas, (Tables 8.3-1, 8.3-2, and 8.3-3).

The visibility modeling predicted a small number of days in excess of the 5% FLAG threshold value for change in extinction for each of the Class I areas. (Tables 8.3-1, 8.3-2, and 8.3-3). The FLM has judged the modeled impacts to be insignificant, because the frequency of the exceedances is small (3 days per year) and the magnitude is only marginally above the 5% visibility impact threshold.

In addition, the modeling results provided information on total nitrogen and sulfur deposition rates. (Tables 8.3-1, 8.3-2, and 8.3-3)
These values were compared to the US National Park Service (USNPS) and US Fish and Wildlife Service (USFWS) deposition analysis thresholds (DAT) for western states. The modeling results yielded a deposition value for total nitrogen that did not exceed the DAT at any of the Class I areas. The modeling results for deposition of total sulfur are marginally above the 0.005 kg/ha-year threshold value. The FLM has judged that this impact is insignificant.

TABLE 8.3-1: CALPUFF Modeled Impacts – Dome Land

Year of Meteorological Data	Modeled Scenario					
Concentration	NO_2 (µg/m³)	PM_{10} (µg/m³)		SO_2 (µg/m³)		
	Annual	24-hour	Annual	3-hour	24-hour	Annual
Max (1999-2004)	0.005	0.08	0.011	0.73	0.17	0.012
Threshold	0.1	0.3	0.2	1	0.2	0.1
Exceed?	No	No	No	No	No	No

Year of Meteorological Data	Modeled Scenario		
Visibility	Reduction (%)	Days > 5%	Days > 10%
Max(1999-2004)	6.76	16	0
Threshold	5	0	0
Exceed?	**Yes**	**Yes**	No

Year of Meteorological Data	Modeled Scenario	
Deposition	Total N (kg/ha/yr)	Total S (kg/ha/yr)
Max	0.002	0.006
Threshold	0.005	0.005
Exceed?	No	**Yes**

TABLE 8.3-2: CALPUFF Modeled Impacts - San Rafael

Year of Meteorological Data	Modeled Scenario					
Concentration	NO_2 (µg/m³)	PM_{10} (µg/m³)		SO_2 (µg/m³)		
	Annual	24-hour	Annual	3-hour	24-hour	Annual
Max (1999-2004)	0.005	0.079	0.01	0.66	0.17	
Threshold	0.1	0.3	0.2	1	0.2	0.1
Exceed?	No	No	No	No	No	No

Year of Meteorological Data	Modeled Scenario		
Visibility	Reduction (%)	Days > 5%	Days > 10%
Max	6.59	12	0
Threshold	5	0	0
Exceed?	**Yes**	**Yes**	No

Year of Meteorological Data	Modeled Scenario	
Deposition	Total N (kg/ha/yr)	Total S (kg/ha/yr)
Max	0.0015	0.0052
Threshold	0.005	0.005
Exceed?	No	**Yes**

TABLE 8.3-3: CALPUFF Modeled Impacts - Sequoia

Year of Meteorological Data	Modeled Scenario					
Concentration	NO_2 (μg/m^3)	PM_{10} (μg/m^3)		SO_2 (μg/m^3)		
	Annual	24-hour	Annual	3-hour	24-hour	Annual
Max (1999-2004)	0.003	0.072	0.007	0.43	0.12	0.007
Threshold	0.1	0.3	0.2	1	0.2	0.1
Exceed?	No	No	No	No	No	No

Year of Meteorological Data	Modeled Scenario		
Visibility	Reduction (%)	Days > 5%	Days > 10%
Max	6.23	2	0
Threshold	5	0	0
Exceed?	**Yes**	**Yes**	No

Year of Meteorological Data	Modeled Scenario	
Deposition	Total N (kg/ha/yr)	Total S (kg/ha/yr)
Max	0.0011	0.0035
Threshold	0.005	0.005
Exceed?	No	No

9. Additional Impact Analysis

9.1. Growth Analysis

The purpose of the growth analysis is to project the industrial, commercial, and residential growth, and related emissions, that are anticipated to occur in the area due to the construction of the new major source or modification. The emissions associated with such projected growth are those not directly related to the new source or modification.

The proposed project outlined in this application is not expected to create more than 30 new full-time positions, which will result in total employment below historic levels at the Shell Refinery (250 after CFP vs. 270 peak historic). The Bakersfield metropolitan statistical area (MSA) has a population of approximately 270,000 people (247,057 according to the 2000 census). Thus, any industrial, commercial, and residential growth associated with the proposed project will not be substantial compared to the size of the Bakersfield industrial, commercial and population base. No appreciable increase in emissions is expected because of growth associated with the proposed project. It is anticipated that hiring for the construction phase of the project would be done, primarily, from the surrounding communities, as would hiring of some of the operations personnel. Moreover, no new housing will be required to support the project. Consequently, no significant increase in air pollutant emissions indirectly associated with the proposed project is expected to occur.

9.2. Vegetation Analysis

This requirement addresses the potential impact of the proposed project’s emissions on sensitive soils and vegetation, of commercial or recreational value, occurring in the project’s impact area. The NAAQS establish secondary standards that are intended to protect public welfare, including the consideration of economic interests, vegetation, and visibility. While ambient concentrations of criteria pollutants below the secondary NAAQS are expected to be protective of most soil types and vegetation, this may not be true for particularly sensitive soils or plant species. The potential impacts of the proposed project were compared to relevant thresholds, including but not limited to, secondary NAAQS, to determine effects on soil and vegetation.

Table 9.2-1 presents the reported minimum exposure levels at which visible damage to or growth retardation of plants may occur. The data reflect studies that were conducted primarily on crops of commercial value.

The Applicant has conducted an analysis of the potential effects of NO_2, CO, and SO_2 emissions on vegetation surrounding the site. Based on a comparison of maximum predicted concentrations to the respective thresholds shown in Table 9.2-1, the project's impacts are significantly below threshold screening values, and therefore will not adversely affect crops grown in the area.

Soils in the impact area, which would be affected mainly through the deposition and subsequent leaching of particulate contaminants, are not expected to be adversely affected.

TABLE 9.2-1: Comparison of Maximum Predicted Project Concentrations with Plant Effect Screening Thresholds

Pollutant	Averaging Period	Maximum Predicted Impact (μg/m³)	Screening Level[a] (μg/m³)
NO_2	Annual	0.63	94-188
	4-Hour	11.5	3,760
SO_2	Annual	0.86	18
	1-Hour	16.4	917
	3-Hour	8.26	786
CO	1-Hour	42.1	1,800,000

[a] Level associated with most sensitive species. Based on information in the EPA document: A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (USEPA, 1980). Concentrations reflect atmospheric conditions of 20°C and 1 atmosphere.

9.3. Visibility Impairment Analysis

EPA guidance indicates that visibility impairment within the impact area of proposed new major sources or modifications should be evaluated. This is a visibility assessment for Class II areas. The EPA guidance suggests a tri-level screening procedure, in which the VISCREEN model is used as a first-level screen. Depending on the outcome of the first-level screen, the VISCREEN model may be used to conduct a second-level screen, using information more specific to the source, topography, and local meteorological conditions. If the Level 1 and the Level 2 screening analyses indicate the possibility of visibility impairment, then use of a more sophisticated plume visibility model in a third-level screen is suggested.

A conservative Level 1 analysis was conducted using the EPA VISCREEN model to evaluate the visibility impacts in the Class II area surrounding the Big West refinery. The analysis is conservative given the use of very stable atmospheric dispersion coupled with a very low wind speed persisting for 12 hours and a wind direction that would transport the plume directly adjacent to the observer. Source emissions input were the maximum short-term rates for NOx and PM10 for the proposed units. Model default emission rates (i.e., zero emissions) were selected for primary NO2, soot, and sulfate. A background visual range of 110 km and a background (default) ozone concentration of 0.04 ppm were used. The background visual range corresponds with that identified for the area in Figure 9 of the Workbook for Plume Visual Impact Screening and Analysis (Revised) (EPA, 1992). The actual background visual range for the area is unknown, but the value of 110 km used in this analysis is likely conservative given the agricultural and industrial activity in the area.

To assess the proposed project's impact on a scenic view in the area, the state parks located in the county were identified. The closest state park to the refinery is the Tule Elks State Reserve, which is located approximately 25 km to the west-southwest of the refinery.

The potential for plume visual impacts is directly related to the stability of the atmosphere and to the presumed background visual range. Visibility effects thresholds have not been established for Class II areas, and the Level 1 procedure automatically compares the impacts against Class I thresholds. Without plume visual impact standards for Class II areas, it is difficult to be conclusive regarding the nearby visual effect of plumes from the project. Preliminary estimates of delta E under stable atmospheric conditions slightly exceed FLAG levels of concern for Class I areas. This is not judged to be significant for a Class II area.

10. Endangered Species Act

Pursuant to Section 7 of the Endangered Species Act (ESA), 16 U.S.C. 1536, and its implementing regulations at 50 C.F.R. Part 402, EPA is required to ensure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. EPA has determined that this PSD permitting action is subject to ESA Section 7 requirements.

For this project, the Applicant initiated contact with the U.S. Fish and Wildlife Service (USFWS) by requesting concurrence from them that the construction and operation of the Clean Fuels Project is not likely to adversely affect species protected by the ESA. This request was made after the Applicant had engaged in informal consultation with FWS for several months. In particular, the consultation focused on the potential impacts to the federally endangered San Joaquin kit fox. The Applicant prepared and submitted a biological assessment (BA) detailing the potential impacts of the project on the San Joaquin kit fox and proposing mitigation measures that it committed to implementing. Based on the information and proposed impact minimization measures provided by the Applicant, the FWS determined that the proposed project has the potential to adversely affect the kit fox. Therefore, the FWS concluded that a formal consultation pursuant to Section 7(a)(2) of the ESA is required.

EPA initiated formal consultation with the FWS on December 27, 2006. The FWS is preparing a biological opinion (BO) to address potential impacts from this project, as well as from related projects to construct a bridge over the Friant-Kern canal, and to construct four new gas liquids pipelines from Inergy Propane, LLC to the Big West Bakerfield refinery. EPA will not finalize a PSD permit allowing construction to commence for the Clean Fuels Project until a BO is issued by FWS, and until the Applicant commits to implementing any proposed mitigation measures outlined in the BO.

11. Conclusion and Proposed Action

EPA is proposing to issue a PSD permit to Big West of California, LLC for the construction of the Clean Fuels Project at the existing Bakersfield refinery. We believe that the proposed project will comply with PSD requirements, including the installation and operation of equipment to achieve BACT-level emission control, and will not cause or contribute to a violation of the NAAQS, or of any PSD increment. We have made this determination based on the information supplied by the applicant and our review of the analyses contained in the permit application. EPA will provide the proposed permit and this Statement of Basis and Ambient Air Quality Impact Report to the public for review, and will make a final decision after considering all public comments on our proposal.